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PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpco.com (web site)

OTTER TAIL
Power Company

February 8, 2000

Mr. William Grimley
Emission Measurement Center (MD-19)
U. S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

Attn: Electric Utility Steam Generating Unit Mercury Test Program

Dear Mr. Grimley:

SUBJECT: SPECIATED MERCURY TEST REPORT – COYOTE STATION

Enclosed are two bound and one unbound copy of the Speciated Mercury Emissions Testing performed for Otter Tail Power Company at the Coyote Station Unit B1 Inlet and Outlet Ducts. The testing was performed on September 28 and 29, 1999 by Braun Intertec. The report was prepared by Mostardi-Platt Associates, Inc.

Should you have any questions on our submittals, please contact me at 218-739-8407 or at tgraumann@otpco.com.

Sincerely,

Terry Graumann
Manager, Environmental Services

Enclosures

C. Mr. Jeffery L. Burgess
Director, Division of Environmental Engineering
North Dakota Department of Health
1200 Missouri Ave.
P. O. Box 5520
Bismarck, ND 58506-5520

SPECIATED MERCURY EMISSIONS TESTING

Performed For
OTTER TAIL POWER COMPANY

At The
Coyote Station
Unit B1
Inlet and Outlet Ducts
Beulah, North Dakota

Test Date
September 28 and 29, 1999

Mostardi Platt

platt

Mostardi-Platt Associates, Inc.
A Full-Service
Environmental Consulting
Company

945 Oaklawn Avenue
Elmhurst, Illinois 60126-1012
Phone 630-993-9000
Facsimile 630-993-9017

Mostardi Platt

SPECIATED MERCURY EMISSIONS TESTING

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September 28 and 29, 1999

MOSTARDI PLATT PROJECT 92827
DATE SUBMITTED: FEBRUARY 7, 2000

TABLE OF CONTENTS

Table of Figures

Table of Tables

CERTIFICATIONS REQUIRED FOR PERFORMANCE TEST REPORTS

FORM CERT1
June 1999

NOTE: All performance test reports must contain a certification by the responsible parties that the test results have been reported accurately, that the field data is a true representation of the sampling procedures and that the process data is a true indicator of the operating parameters of the emissions unit at the time of the performance test. (Ref. Minn. R 7017.2040). Performance test results will not be accepted without certification of the report.

1. Certification of sampling procedures by the team leader of the personnel conducting the sampling procedures:
"I certify under penalty of law that the sampling procedures were performed in accordance with the approved test plan and that the data presented in this test report are, to the best of my knowledge and belief, true, accurate, and complete. All exceptions are listed and explained below."

Bruce Randall mgq

Signature:

Bruce Randall

Printed Name of Person

Regional Manager

Title

2/7/2000

Date

2. Certification of analytical procedures by the person responsible for the laboratory analysis of field samples:
"I certify under penalty of law that the analytical procedures were performed in accordance with the requirements of the test methods and that the data presented for use in the test report were, to the best of my knowledge and belief, true, accurate, and complete. All exceptions are listed and explained below."

Signature:

Printed Name of Person

Title

Date

3. Certification of test report by the senior staff person at the testing company who is responsible for compiling and checking the test report:
"I certify under penalty of law that this test report and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the test information submitted. Based on my inquiry of the person or persons who performed sampling and analysis relating to the performance test, the information submitted in this test report is, to the best of my knowledge and belief, true, accurate, and complete. All exceptions are listed and explained below."

Scott W. Banach

Signature:

Scott W. Banach

Printed Name of Person

Director, Project Engineering

Title

2/7/2000

Date

4. Certification of test report by owner or operator of the emission facility:
"I certify under penalty of law that the information submitted in this test report accurately reflects the operating conditions at the emission facility during this performance test and describes the date and nature of all operational and maintenance activities that were performed on process and control equipment during the month prior to the performance test. Based on my inquiry of the person or persons who performed the operational and maintenance activities, the information submitted in this test report is, to the best of my knowledge and belief, true, accurate, and complete. All exceptions are listed and explained below."

Terry Braun

Signature:

Terry Graumann

Printed Name of Person

Mgr. Environmental Services

Title

02/08/00

Date

This form is to be submitted as part of the performance test report to: North, Metro, or South District, Performance Test Coordinator, MN Pollution Control Agency, 520 Lafayette Rd., St. Paul, MN 55155-4194.

1.0 INTRODUCTION

1.1 SUMMARY OF TEST PROGRAM

The U.S. Environmental Protection Agency (EPA), is using its authority under section 114 of the Clean Air Act, as amended, to require that selected coal-fired utility steam generating units provide certain information that will allow the EPA to calculate the annual mercury emissions from each unit. This information will assist the EPA Administrator in determining whether it is appropriate and necessary to regulate emissions of Hazardous Air Pollutants (HAPs) from electric utility steam generating units. The Emission Measurement Branch (EMB) of the Office of Air Quality Planning and Standards (OAQPS) oversees the emission measurement activities. Braun Intertec Corporation (Braun Intertec) conducted the emission measurements. Braun Intertec retained MOSTARDI-PLATT ASSOCIATES, INCORPORATED (Mostardi-Platt) to prepare this report.

EPA selected the Otter Tail Power Company (OTPC) Coyote Station in Beulah, North Dakota to be one of seventy-eight coal-fired utility steam generating units to conduct emissions measurements. The test performed at Unit B1 was the only test at this facility, and it was conducted on September 28 and 29, 1999. Simultaneous measurements were conducted at the inlet and outlet of the Spray Dryer/Baghouse. Mercury emissions were speciated into elemental, oxidized and particle-bound mercury using the Ontario-Hydro test method. Fuel samples were also collected concurrently with Ontario-Hydro samples in order to determine fuel mercury content.

1.2 KEY PERSONNEL

The key personnel who coordinated the test program and their telephone numbers are:

- Braun Intertec Project Manager - Bruce Randall (651) 686-0700
- OTPC Manager of Environmental Services – Terry Graumann (218) 739-8407
- OTPC Coyote Station Contact/Process Monitor – Brad Zimmerman (701) 873-2571

2.0 PLANT AND SAMPLING LOCATION DESCRIPTIONS

2.1 PROCESS DESCRIPTION

Figure 2-1 illustrates the basic operational steps for this coal-fired steam generator. The steps are:

1. Lignite coal is delivered from the mine tipple to the unit's twelve coal silos (six on each side of the boiler).

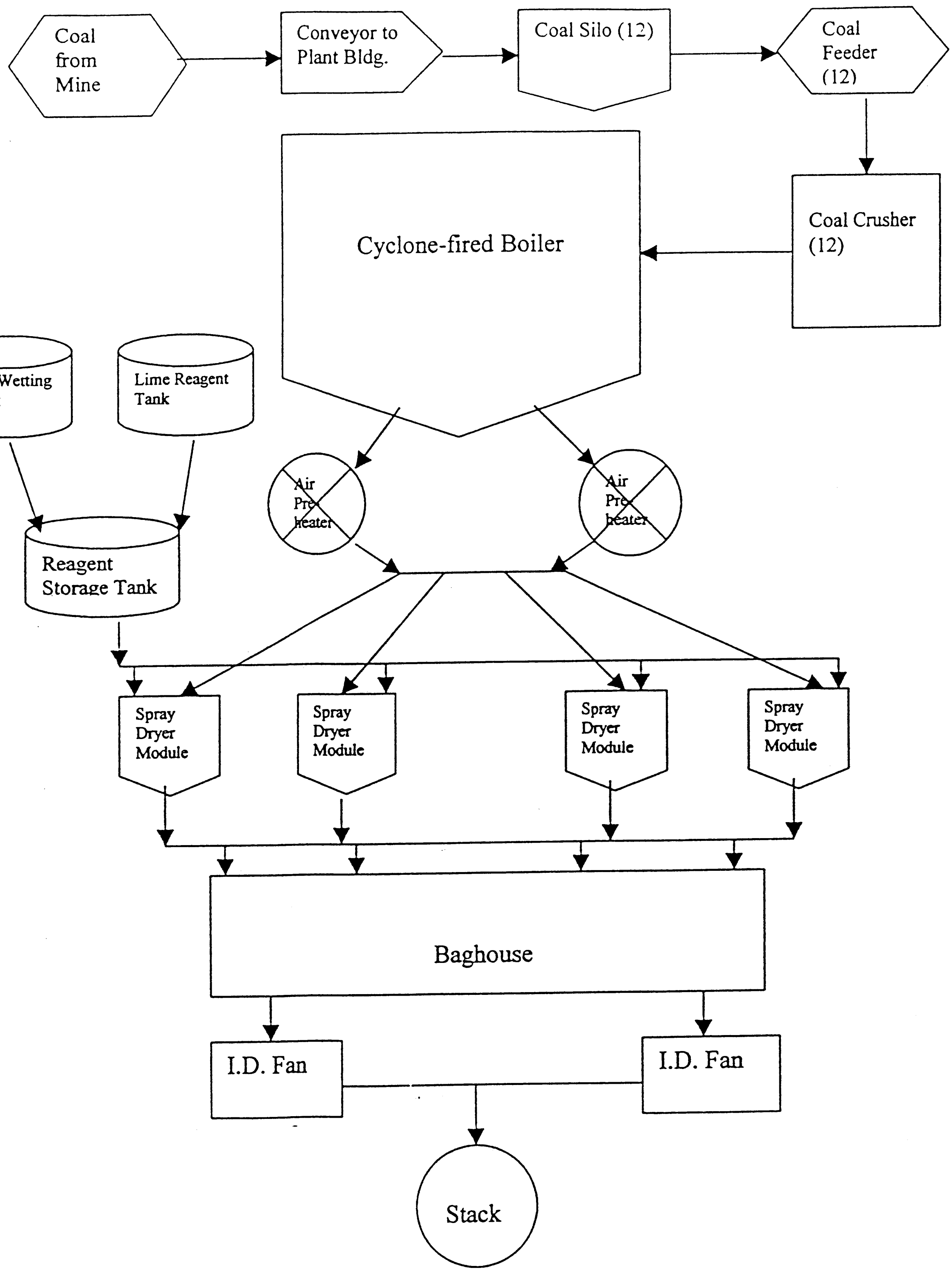
2. Lignite coal is combusted in the boiler.

3. Flue gas flows from the boiler through the air pre-heater to the spray dryer and then to the baghouse.

4. Flue gas exits via the induced draft fan and then the stack.

At the Coyote Station, lignite coal from the Beulah Mine is used. The Coyote Station utilizes a Babcock and Wilcox cyclone-fired boiler, Model RBC48/CY. The unit has a maximum rated heat input of 5,800 MMBtu per hour. The unit began commercial operation on May 1, 1981. It is regulated as a 40 CFR Part 60 Subpart D unit.

Sulfur dioxide and particulate emissions are controlled by an ASEA Brown Boveri Environmental Systems Flue Gas Desulfurization System. The design flue gas flow rate is 1,287,000 SCFM.



OTTER TAIL Power Company

Coyote Station
Process Flow Chart
Figure 2-1

2.2 CONTROL EQUIPMENT DESCRIPTION

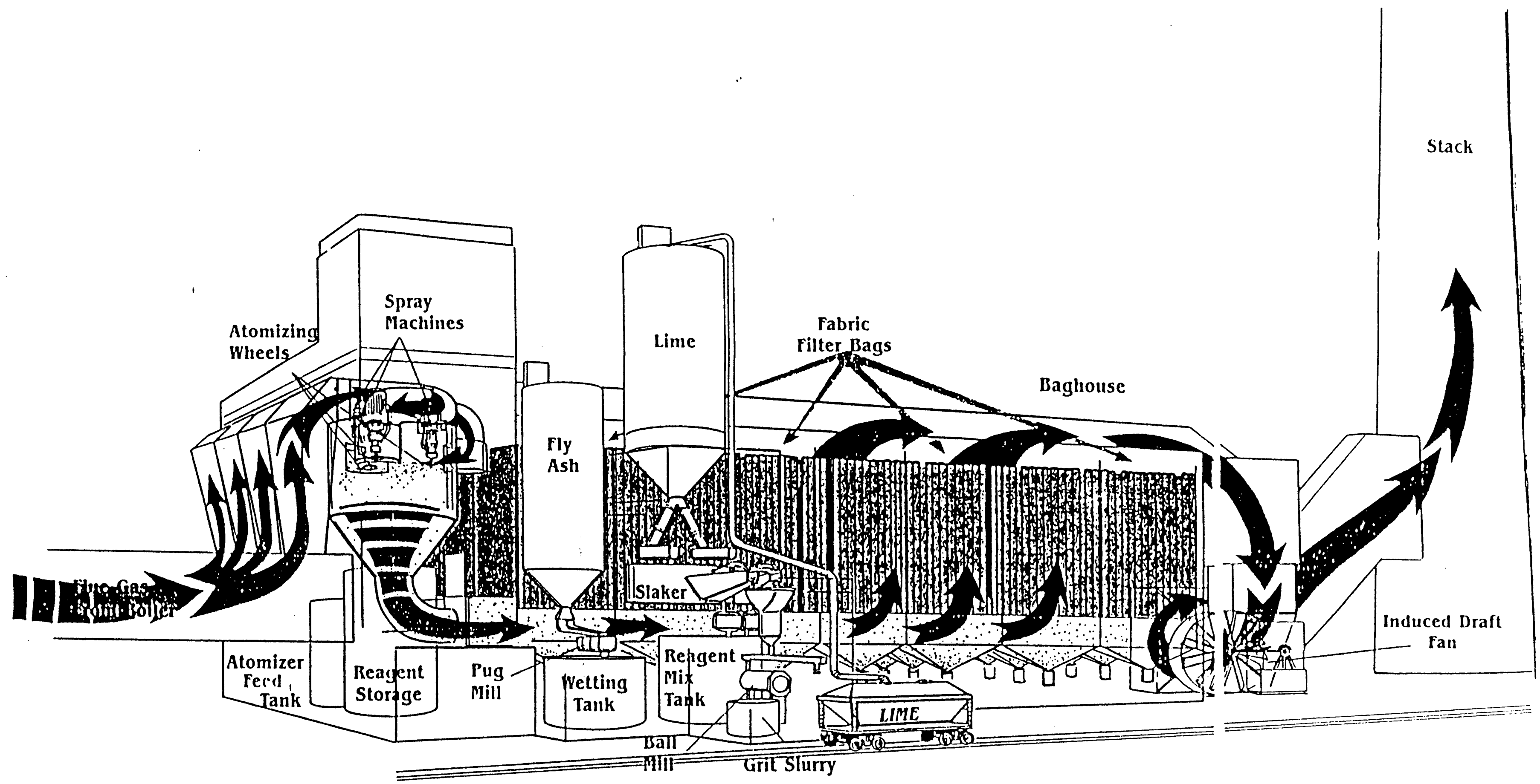
Sulfur dioxide and particulate matter emissions from the boiler (furnace) are controlled by a spray dryer/baghouse combination manufactured by ASEA Brown Boveri Environmental Systems. Figure 2-2 is a schematic of the spray dryer/baghouse sulfur dioxide and particulate control equipment.

The system consists of four spray dryer modules with three atomizing wheels per module. A blend of slaked lime and fly ash is used as the reagent slurry. Following treatment in the spray dryer, particulate matter is removed from the flue gas in the baghouse. The 38-cell baghouse contains 7,752 Teflon-coated fiberglass fabric filter bags.

Table 2-1 presents a summary of the normal ranges of operating parameters for the scrubber/baghouse.

Table 2-1: Ranges of Spray Dryer/Baghouse Operating Parameters

Parameter	Typical Range	Control System Point Name
Dryers in service.	2-4	Manual (No computer pt.)
Slurry flow to Dryers.	80-600 gpm	ABCD_FLOW.PV
Recycle ratio	1:1 up to 5.0:1 (Flyash:Lime)	QC0300A.PV
Inlet SO2 in ppm.	400-1800 ppm	AT0303.PV
Gas inlet temperatures	280-390°F	TT0120A.PV (B,C,D)
Gas outlet temperatures	175-225°F	TY0130A.PV (B,C,D)
Baghouse compartments out of service	0-3	OUT_SERV.PV
Pressure drop across the baghouse.	3-10 inches water	BHPDP.PV



Coyote Station
Control Equipment
Schematic
Figure 2-2

OTTER TAIL Power Company

2.3 FLUE GAS SAMPLING LOCATIONS

Emissions sampling was conducted at: (1) the inlet to the spray dryer/baghouse, and (2) the main stack. Figures 2-3 and 2-4 are schematics of these sampling locations.

2.3.1 Spray Dryer/Baghouse Inlet. See Figures 2-3 and 2-3(a). Sampling was conducted at the inlet to one of the four spray dryer modules. There are seven 6-inch test ports located on the horizontal portion of the duct near the spray dryer inlet. The test ports are located between the damper and the spray dryer building enclosure. At that point, the inside duct dimensions are approximately 192 inches wide by 85 inches high. Gas temperature at this location is approximately 310°F. Duct static pressure was approximately -17 " H_2O. This was the only practical location for sampling control equipment inlet conditions. Prior to testing, it was found that one of the seven ports could not be opened. Thus, sampling was conducted from six ports.

The inlet location does not meet the port placement criteria of EPA Method 1. The Ontario-Hydro Method (Section 10.1.5) requires that sample be collected for not less than two hours, and not more than three hours. The method further requires that sample be collected for at least five minutes at each traverse point. Thus, sampling was conducted at four traverse points in each of the six ports (twenty-four total points). Sample duration was five minutes per traverse point, for a total sample time of one hundred and twenty (120) minutes. Traverse point locations are presented below:

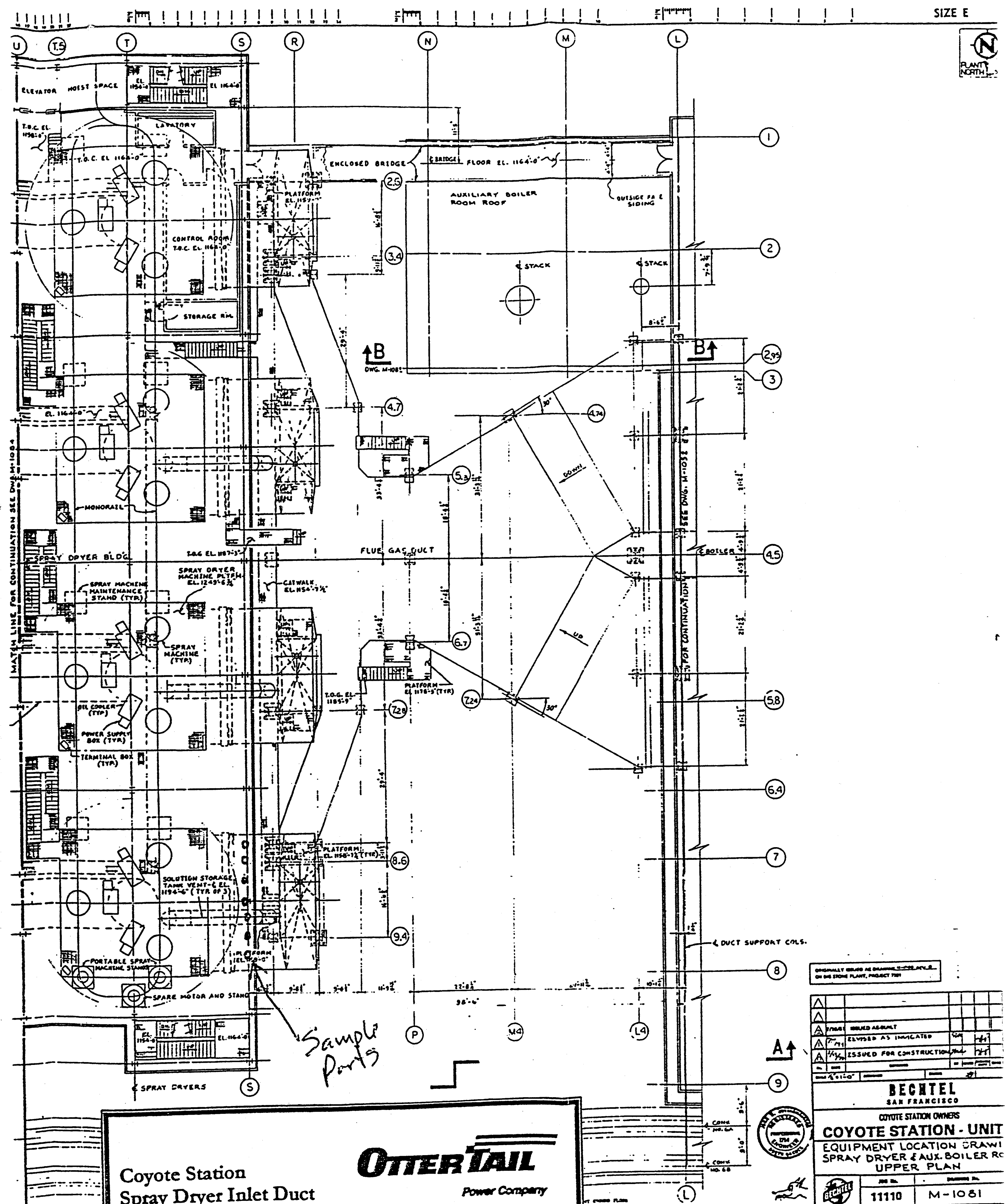
Traverse Point Number	Distance From Inside Top Wall (inches)
1	10.6
2	31.9
3	53.2
4	74.4

Based on the configuration of the inlet duct, it is possible that flow conditions may exceed the cyclonic limitations of Method 1. Per the "Electric Utility Steam Generating Unit Mercury Emissions" web page, no modifications to the sampling procedure will be made, since ". . .(a) mercury is primarily in the gaseous phase and is not impacted by uncertainties in the gas flow and isokinetic sampling rate, and (b) stratification of mercury species is not expected."

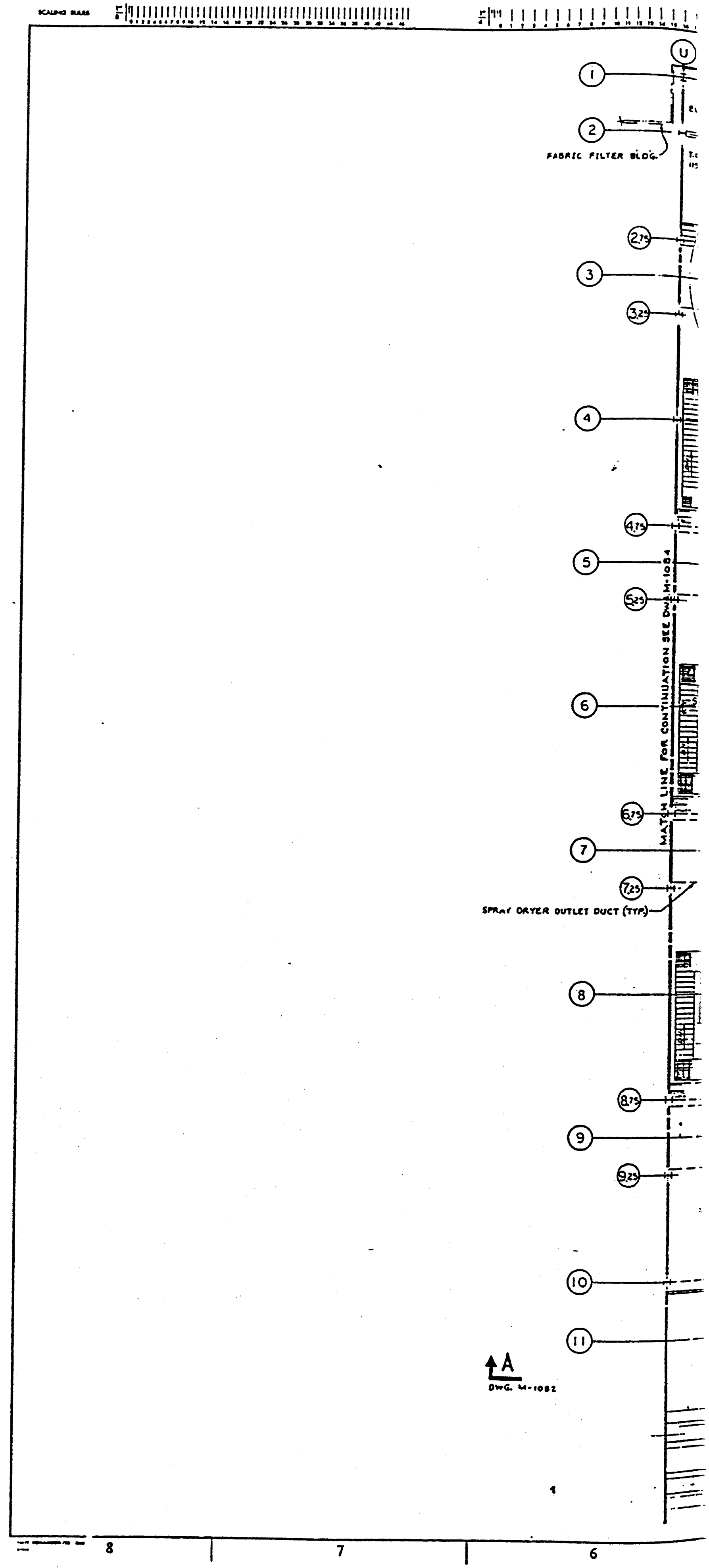
2.3.2 Main Stack. See Figure 2-4. The diameter of the main stack at the sample location is 252 inches. The main stack is equipped with four 4" inch sample ports. Gas temperature at this location is expected to be approximately 185°F, with a static pressure of -0.9"H_2O.

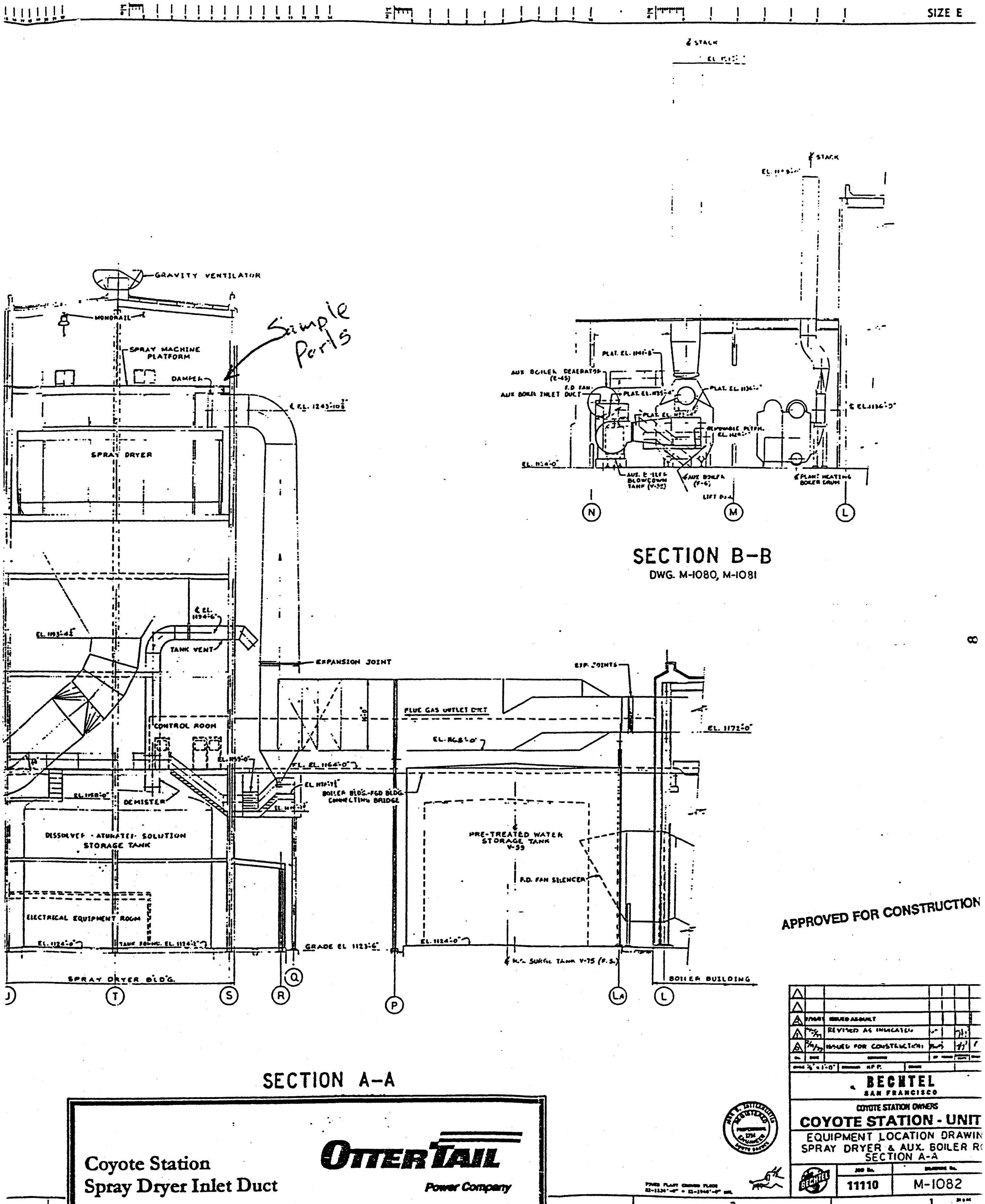
The sample ports are located 217.25 feet (10.3 duct diameters) downstream of the flue gas entry to the stack, and 210.75 feet (10 duct diameters) upstream of the stack exit. Sampling was conducted at a total of twelve traverse points, three in each of the four ports. Sample duration was ten minutes per traverse point, for a total sample duration of one hundred and twenty (120) minutes. The traverse point locations are presented below:

Traverse Point Number	Distance From Inside Wall (inches)
1	11.1
2	36.8
3	74.6



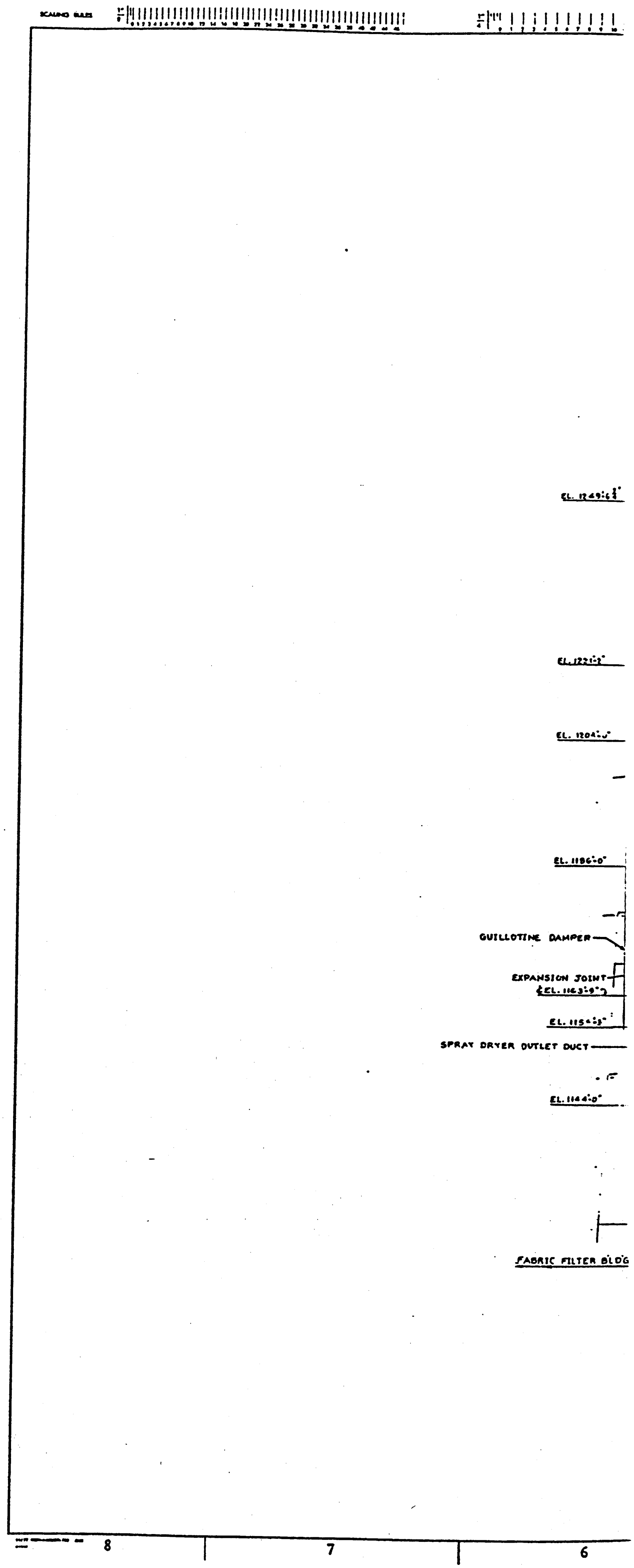
Coyote Station
Spray Dryer Inlet Duct
Figure 2-3

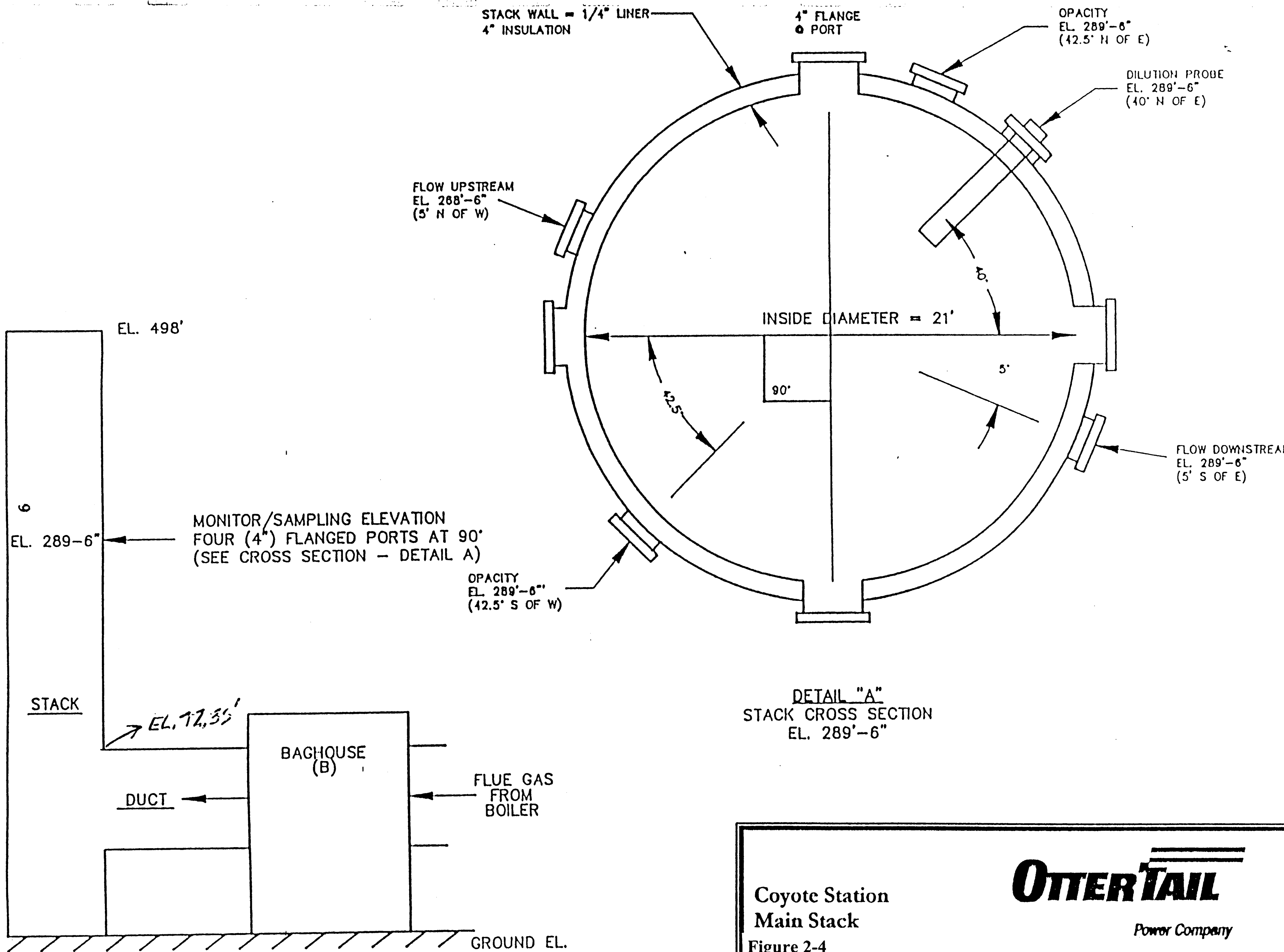

SCALING RULES
U
1
2
FABRIC FILTER BLDG.
2.75
3
3.25
4
4.75
5
5.25
6
6.75
7
7.25
SPRAY DRYER OUTLET DUCT (TYP.)
8
8.75
9
9.25
10
11
MATCH LINE FOR CONTINUATION SEE DWG. M-1084
A
DWG. M-1082
8
7
6



Coyote Station
Spray Dryer Inlet Duct
Figure 2-3(a)

OTTER TAIL Power Company


SCALING RULES
EL. 1249'-6¾"
EL. 1221'-2"
EL. 1204'-0"
EL. 1186'-0"
GUILLOTINE DAMPER
EXPANSION JOINT
℄ EL. 1163'-9"
EL. 1154'-3"
SPRAY DRYER OUTLET DUCT
EL. 1144'-0"
FABRIC FILTER BLDG
8
7
6



OTTER TAIL Power Company

Coyote Station
Main Stack
Figure 2-4

2.4 FUEL SAMPLING LOCATION

Fuel samples were collected from one of the center two coal silos located on each side of the boiler (one sample point on each side of the boiler). Sample was collected from the sample port at the feeder inlet. Four equally spaced (in time) samples were collected from each of the two sample points during each sample run. The eight (total) samples were thoroughly mixed prior to sample reduction by use of a coal sample riffle.

3.0 SUMMARY AND DISCUSSION OF TEST RESULTS

3.1 OBJECTIVES AND TEST MATRIX

The purpose of the test program was to quantify mercury emissions from this unit. This information will assist the EPA Administrator in determining whether it is appropriate and necessary to regulate emissions of Hazardous Air Pollutants (HAPs) from electric utility steam generating units. The specific objectives, in order of priority were:

- Compare mass flow rates of mercury at the three sampling locations (fuel, inlet to and outlet of spray dryer/baghouse.)

- During the test period, obtain process operating data from the Unit B1 boiler and control equipment operating data from the spray dryer/baghouse.

Table 3-1 presents the sampling and analytical matrix and sampling log.

Table 3-1: Sampling Matrix

Run No. Date	Sample Type	Test Method	Location/Clock Time/Sampling Time	
			Inlet	Outlet
1 9/28/99	Speciated Mercury	Ontario Hydro	1130-1405 120	1130-1404 120
2 9/29/99	Speciated Mercury	Ontario Hydro	0830-1052 120	0830-1057 120
3 9/29/99	Speciated Mercury	Ontario Hydro	1200-1422 120	1200-1422 120

3.2 FIELD TEST CHANGES AND PROBLEMS

3.2.1 Inlet Sample Location. As described in 2.3.1, it was not possible to sample at the inlet sample location as was initially planned. For the reasons described in Section 2.3.1, it is not anticipated that this change led to any bias in the determination of mercury concentrations.

3.2.2 Hydroxylamine Sulfate Solution. On July 9, 1999, Bruce Randall received a telephone call from the Energy and Environmental Research Center. The caller informed Mr. Randall that the recipe for this solution was to be revised such that equal amounts of Hydroxylamine Sulfate and Sodium Chloride were utilized. Mr. Randall verbally confirmed this change with Mr. Bill Grimley of EPA. This change was incorporated and utilized.

3.3 PRESENTATION OF RESULTS

3.3.1 Mercury Mass Flow Rates. The mass flow rate of Mercury determined at each sample location is presented in Table 3-2.

Table 3-2: Summary of Results

Sample Location	Elemental Mercury (gram/hr)	Oxidized Mercury (gram/hr)	Particle-Bound Mercury (gram/hr)	Total Mercury (gram/hr)
Fuel				
Run 1				15.9
Run 2				27.6
Run 3				16.9
Average				**20.1**
Scrubber Baghouse Inlet				
Run 1	21.1	2.49	1.05	24.6
Run 2	21.4	4.58	1.81	27.7
Run 3	22.8	4.70	2.58	30.1
Average	**21.8**	**3.92**	**1.81**	**27.5**
Main Stack				
Run 1	18.5	0.120	0.111	18.72
Run 2	0.3	0.321	0.190	0.808
Run 3	23.6	0.581	0.102	24.3
Average All Runs	**14.1**	**0.341**	**0.134**	**14.6**
Average Runs 1 & 3	**21.1**	**0.351**	**0.107**	**21.5**

The mass flow rate of speciated mercury measured during the second run at the main stack is significantly less than the subsequent two runs. The acidified potassium permanganate fraction of the Elemental Mercury sample was mis-handled in the laboratory, and as such, could not be analyzed. Results are presented in Table 3-2 based on the average of all three runs at the main stack, as well as based on the average of Runs 1 and 3. The latter is more representative of actual mercury emissions.

3.3.2 Comparison of Volumetric Flow Rate. Volumetric flow rate is a critical factor in calculating mass flow rates. Ideally, the volumetric flow rate (corrected to standard pressure and temperature) measured at the inlet to the control device should be the same as that measured at the stack, which should be the same as that measured by the CEMS. A comparison of volume flow rates measured a the three locations is presented in Table 3-3.

Table 3-3: Comparison of Volumetric Flow Rate Data

	Inlet (one of 4 spray dryers) KACFM/KSCFM/KDSCFM	Stack KACFM/KSCFM/KDSCFM	CEMS KSCFM
Run 1	322.7/197.0/169.9	2,039/1,477/1,252	1,388
Run 2	342.5/201.5/172.9	2,008/1,493/1,243	1,402
Run 3	348.8/204.3/175.8	2,009/1,473/1,266	1,399
Average	338.0/200.9/172.9	2,019/1,481/1,254	1,396

The measured volumetric flow rate (KSCFM) at the inlet was approximately 13.5% of the total flow rate measured at the stack. Prior to the tests, it was anticipated that volumetric flow rate may not be equally divided among the four spray dryer inlet ducts, and this proved to be the case. In order to compensate for this difference, mass flow rates of mercury at the Inlet were calculated using the Stack volumetric flow rate (KSCFM) corrected to Inlet moisture content.

The measured volumetric flow rate at the stack (KSCFM) was approximately 5.7% higher than that determined by the CEMS. Percent differences of this magnitude should be considered to be very good, and indicate that mass flow rates of mercury calculated based on this data should be representative.

3.3.3 Individual Run Results. A detailed summary of results for each sample run at the inlet and main stack are presented in Tables 3-4 and 3-5, respectively.

Table 3-4: Inlet Individual Run Results

Parameter	Run 1	Run 2	Run 3	Average
Sample Date	9/28/99	9/29/99	9/29/99	
Clock Time	1130-1405	0830-1052	1200-1422	
Sample Time	120	120	120	120
Average Duct Temperature (oF)	325	348	351	341
Average Duct Velocity (ft/s)	47.5	50.3	51.3	49.7
Moisture Content (%vol)	13.8	13.7	14.0	13.8
CO_2 Content (%vol dry)	11.8	11.7	11.8	11.7
O_2 Content (%vol dry)	8.2	8.3	8.2	8.2
Fo	1.076	1.077	1.076	1.076
Wet Molecular Weight (g/g-mole)	28.53	28.53	28.51	28.5
Volume Flow Rate (ACFM)	322730	342110	348770	337870
Volume Flow Rate (SCFM)	196950	201250	204260	200820
Volume Flow Rate (DSCFM)	169850	173700	175750	173100
Coal Feed Rate (ton/hr)	307.3	313.1	305.0	308.5
Coal Hg Content (ug/g, as received)	0.057	0.097	0.061	0.072
Sample Volume (dscf)	64.504	63.756	64.769	64.343
Net Elemental Hg (μg)	17.77	17.71	19.44	18.31
Net Oxidized Hg (μg)	2.1	3.8	4.0	3.3
Net Particle-Bound Hg (μg)	0.89	1.5	2.2	1.53
Total Hg (μg)	20.76	23.01	25.64	23.14
Elemental Hg ER (gram/hr)	21.05	21.48	22.82	21.78
Oxidized Hg ER (gram/hr)	2.49	4.61	4.70	3.93
Particle-Bound Hg (gram/hr)	1.05	1.82	2.58	1.82
Total Hg (gram/hr)	24.60	27.91	30.10	27.54
Sample Percentage of Isokinetic (%)	101.1	97.7	98.1	99.0

Table 3-5: Main Stack Individual Run Results

Parameter	Run 1	Run 2	Run 3	Average
Sample Date	9/28/99	9/29/99	9/29/99	
Clock Time	1130-1404	0830-1057	1200-1422	
Sample Time	120	120	120	120
Average Duct Temperature (oF)	228	205	215	216
Average Duct Velocity (ft/s)	98.1	96.6	96.7	97.1
Moisture Content (%vol)	15.2	16.8	16.7	16.2
CO_2 Content (%vol dry)	10.3	10.4	10.5	10.4
O_2 Content (%vol dry)	9.8	9.7	9.7	9.7
Fo	1.078	1.077	1.067	1.074
Wet Molecular Weight (g/g-mole)	28.20	28.03	28.05	28.09
Volume Flow Rate (ACFM)	2038900	2008200	2009300	2018800
Volume Flow Rate (SCFM)	1477000	1493000	1472800	1480933
Volume Flow Rate (DSCFM)	1251900	1242800	1226200	1240300
Coal Feed Rate (ton/hr)	307.3	313.1	305.0	308.5
Coal Hg Content (mg/kg, as received)	0.057	0.097	0.061	0.072
Sample Volume (dscf)	61.737	62.747	62.047	62.177
Net Elemental Hg (µg)	15.2	<0.25	19.92	19.92
Net Oxidized Hg (µg)	<0.10	0.27	0.49	.29
Net Particle-Bound Hg (µg)	0.091	0.16	0.086	0.112
Total Hg (µg)	15.39	0.68	20.50	12.19
Elemental Hg ER (gram/hr)	18.49	0.30	23.62	14.14
Oxidized Hg ER (gram/hr)	0.12	0.32	0.58	0.34
Particle-Bound Hg (gram/hr)	0.11	0.19	0.10	0.13
Total Hg (gram/hr)	18.73	0.81	24.30	14.61
Sample Percentage of Isokinetic (%)	95.9	98.1	98.4	97.5

3.3.4 Results of Fuel Analysis. The results of fuel analyses are presented in Table 3-6.

Table 3-6: Results of Fuel Analysis

Parameter	Run 1	Run 2	Run 3	Average
Total Moisture (wt% - as received)	35.23	35.12	35.11	35.15
Ash (wt% - as received)	7.19	8.6	8.23	8.01
Sulfur (wt% - as received)	0.86	1.34	1.14	1.11
Gross Calorific Value (Btu/lb)	7177	6925	7076	7059.3
Mercury (ug/g – as received)	0.057	0.097	0.061	0.072
Chlorine (wt% - as received)	<0.010	<0.010	<0.010	<0.010

3.3.5 Process Operating Data. The process operating data collected during the tests is presented in Table 3-7.

Table 3-7: Process Operating Data

Parameter	Run 1	Run 2	Run 3	Average
Date	9/28/99	9/29/99	9/29/99	
Start-End Time	1130-1420	0830-1050	1200-1420	
Process Data				
Boiler Feedwater Flow (lb/hr)	3,200.25	3,200.83	3,205.43	3,202.17
Gross Load (MW)	405.14	406.29	405.60	405.68
Fuel Flow to Feeders	See Appendices			
Air Heater "A" Inlet Temp.(°F)	774.86	766.55	765.19	768.87
Air Heater "B" Inlet Temp.(°F)	780.64	766.95	768.34	771.98
Spray Dryer Data				
Dryers in Service	4	4	4	4
Slurry Flow to Dryers (gpm)	252.19	399.08	383.89	345.05
Recycle Ratio	4.75	3.25	3.25	3.75
Inlet SO2 (ppmw)	639.86	856.58	868.06	788.17
Dryer Inlet Temp.(°F)	See Appendices			
Dryer Outlet Temp.(°F)	See Appendices			
Baghouse Data				
Avg. Compartments out of Service	0.23	0.27	0.43	0.31
Baghouse ΔP ("H2O)	6.23	6.21	6.37	6.27
CEMS Data				
Opacity (%)	6.03	7.89	8.06	7.33
SO2 (lb/MMBtu)	1.13	1.02	1.14	1.10
SO2 (lb/hr)	5,301.08	4,801.33	5,329.62	5,144.01
CO2 (% wet)	10.38	10.19	10.15	1.10
Flow (KSCFM)	83,260	84,110	83,960	83,777

4.0 SAMPLING AND ANALYTICAL PROCEDURES

4.1 TEST METHODS

4.1.1 Speciated mercury emissions were determined via the draft "Standard Test Method for Elemental, Particle-Bound, and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario-Hydro Method)", dated April 8, 1999. Any revisions to this test method issued after April 8, 1999 but before July 1, 1999 were incorporated. The change in formula for the Hydroxylamine Sulfate recovery solution described in Section 3.2.2 of this report was the only change from the procedures proposed in the Site Specific Test Plan for this project.

The in-stack filtration (Method 17) configuration was utilized at the inlet location. The out-of-stack filtration (Method 5) configuration was utilized at the main stack. Figures 4-1 and 4-2 are schematics of the Ontario-Hydro sampling trains.

Figure 4-3 illustrates the sample recovery procedure. The analytical scheme was per Section 13.3 of the Ontario-Hydro Method.

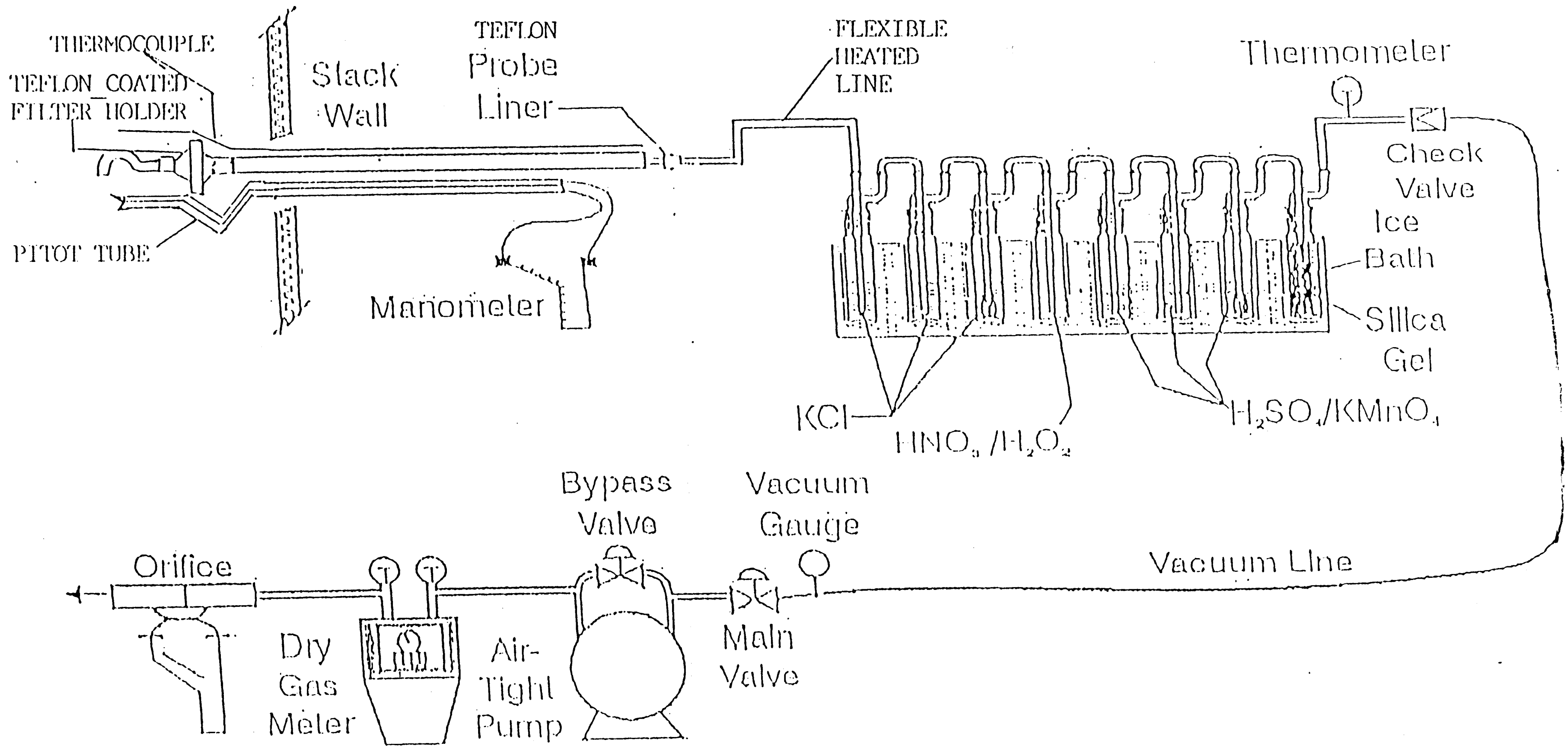


Figure 4-1: Ontario-Hydro Sampling Train (Method 17 Configuration)

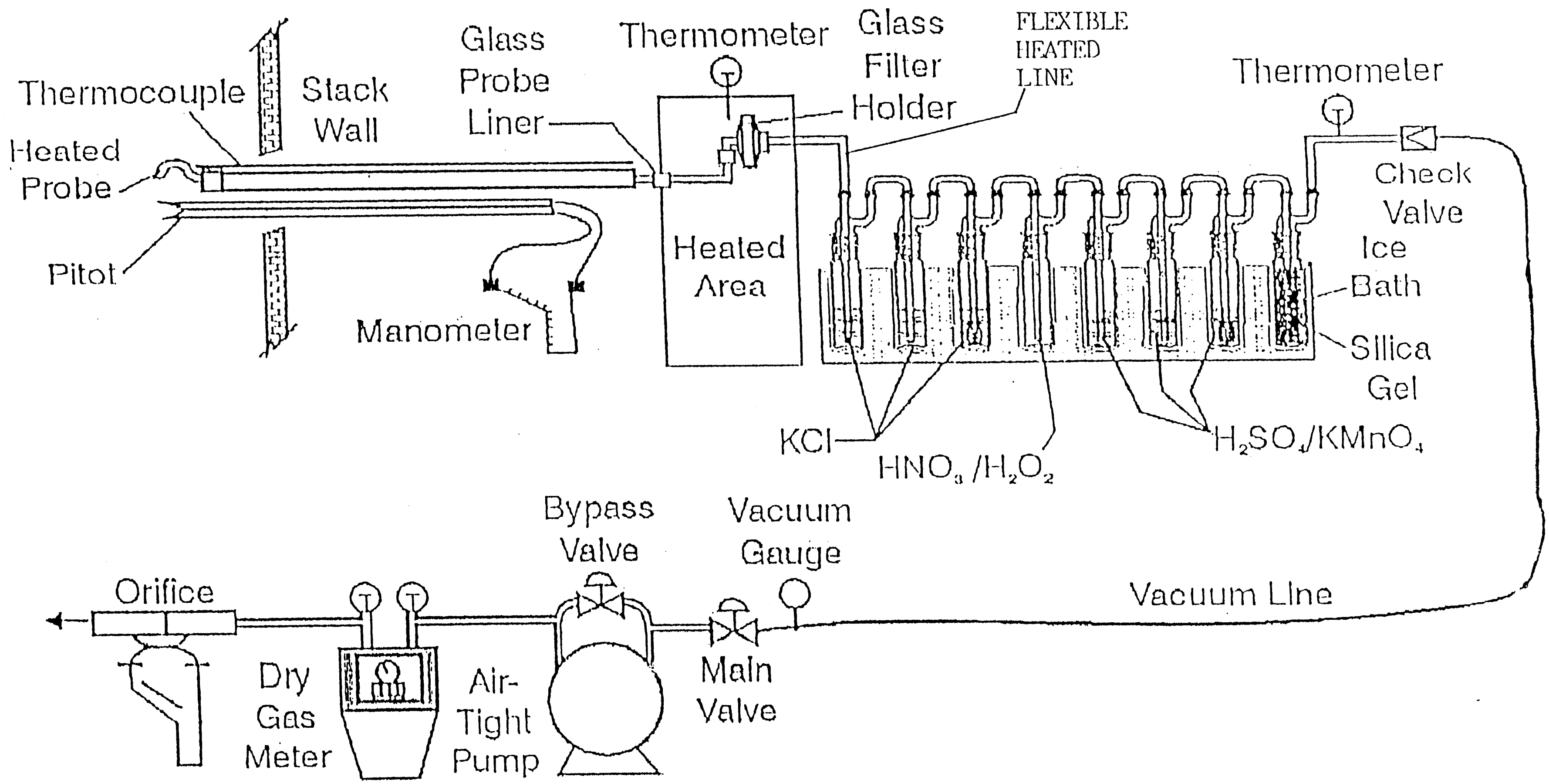


Figure 4-2: Ontario-Hydro Sampling Train (Method 5 Configuration)

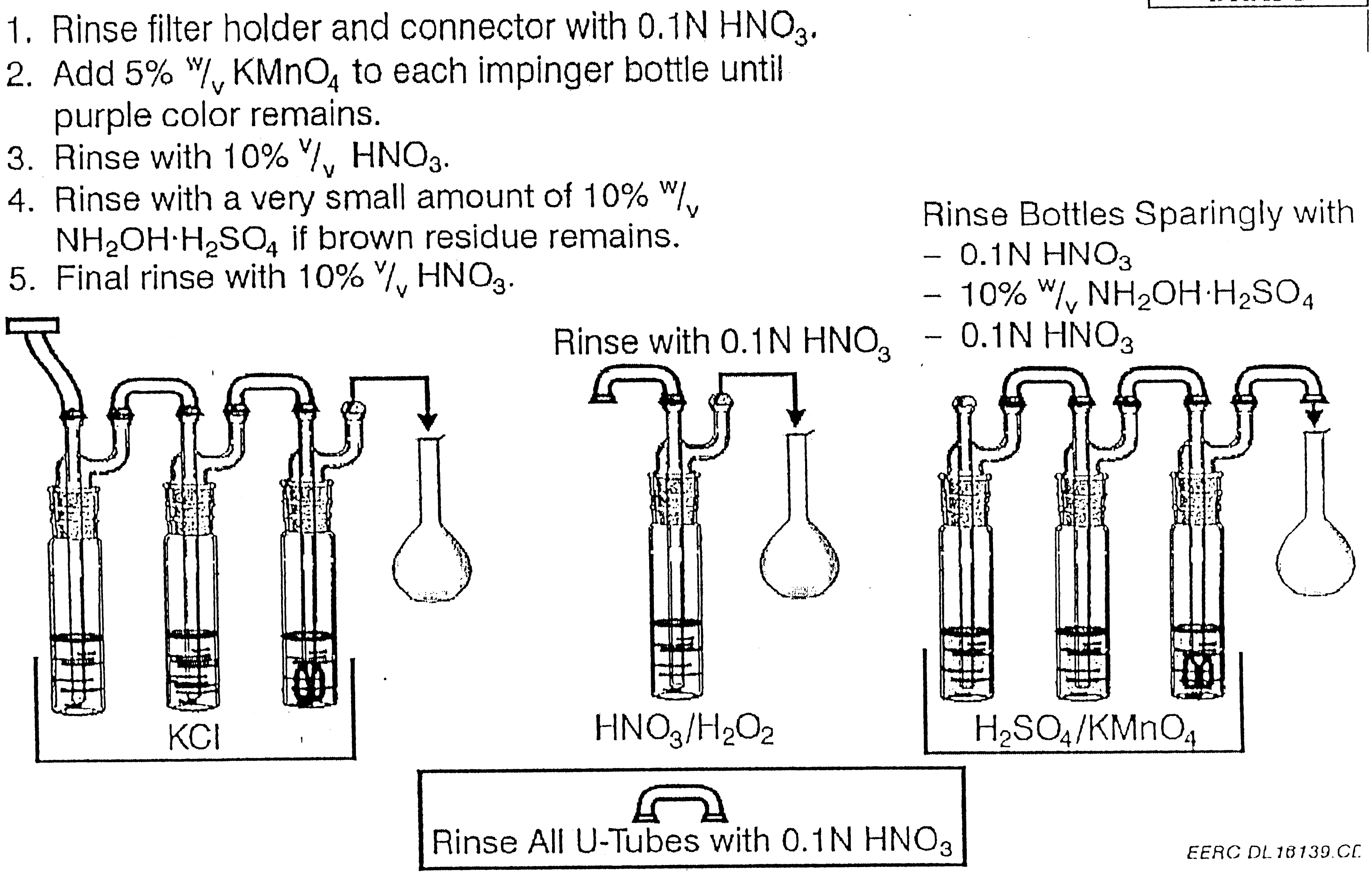


Figure 4-3: Sample Recovery Scheme for Ontario-Hydro Method Samples

4.1.2 Fuel samples were collected by composite sampling. Four samples were collected at equally spaced intervals at each of two sample points during each speciated mercury sampling run. Each set of samples was composited into a single sample for each sample run. Sample analysis was conducted according to Method 7471A.

4.2 PROCEDURES FOR OBTAINING PROCESS DATA

Mr. Brad Zimmerman was responsible for obtaining process operating data. The process data presented in Table 3-6 was continuously monitored via the facility computerized control system and/or the Unit B1 CEMS. Process data was averaged over the course of each sample run. All instruments used to collect process data are routinely calibrated according to OTPC Coyote Station procedures.

5.0 INTERNAL QA/QC ACTIVITIES

5.1 QA/QC PROBLEMS

The only QA/QC problem that occurred during these tests was that a detectable amount of Mercury was found in several blank train fractions. 0.029 µg of Mercury was found in the front-half blank at the main stack – this is approximately 25% of the average amount of Mercury found in the main stack front-half samples. 0.52 µg of Mercury was found in the KCl blank at the control device inlet - this is approximately 16% of the average amount of Mercury found in the inlet KCl samples. 0.14 µg of Mercury was found in the acidified potassium permanganate blank at the control device inlet – this is approximately 1% of the average amount of Mercury found in the inlet acidified potassium permanganate samples. The cause of these blank levels is assumed to be minor contamination at the sample location, as the Mercury concentration in all reagent blanks was less than the analytical detection limit.

5.2 QA AUDITS

5.2.1 Reagent Blanks. As required by the method, blanks were collected for all reagents utilized. The results of reagent blank analysis are presented in Table 5-1.

Table 5-1: Reagent Blank Analysis

Container #	Sample Fraction	Contents	Mercury (µg)	Detection Limit (µ g)
C7/C12	Front-half	0.1N HNO_3/Filter	<0.010	0.010
C8	1 N KCl	1 N KCl	<0.10	0.030
C9	HNO_3/H_2O_2	HNO_3/H_2O_2	<0.25	0.010
C10	$KMnO_4/H_2SO_4$	$KMnO_4/H_2SO_4$	<0.10	0.030

5.2.2 Blank Trains. As required by the method, blank trains were collected at both the inlet and stack sampling locations. These trains were collected on 9/28/99. The results of blank train analysis are presented in Table 5-2.

Table 5-2: Blank Train Analysis

Container #	Sample Fraction	Contents	Mercury (µg)	Detection Limit (µg)
IB C01/C02	Front-half	Filter/front-half rinse	<0.060	0.010
SB C01/C02	Front-half	Filter/front-half rinse	0.029	0.010
IB C03	KCl impingers	Impingers/rinse	0.52	0.030
SB C03	KCl impingers	Impingers/rinse	<0.10	0.030
IB C04	HNO_3-H_2O_2 impingers	Impingers/rinse	<0.25	0.010
SB C04	HNO_3-H_2O_2 impingers	Impingers/rinse	<0.25	0.010
IB C05	$KMnO_4/H_2SO_4$ impingers	Impingers/rinse	0.14	0.030
SB C05	$KMnO_4/H_2SO_4$ impingers	Impingers/rinse	<0.100	0.030

5.2.3 Field Dry Test Meter Audit. The field dry test meter audit described in Section 4.4.1 of Method 5 was completed prior to the test. The results of the audit are presented in Table 5-3. The meter audit for meter number 80664 was performed over the course of 15, rather than 10 minutes.

Table 5-3: Field Meter Audit

Meter Box Number	Pre-Audit Value	Allowable Error	Calculated Yc	Acceptable
81231	0.999	0.9603<Yc<1.029	1.0193	Yes
80664	0.998	0.9681<Yc<1.028	1.0059	Yes

List of Participants

Name	Organization	Project Role
Terry Graumann	OTPC	Manager of Environmental Services
Brad Zimmerman	OTPC - Coyote	Plant Contact/Process Monitor
Bruce Randall	Braun Intertec	Project Director/Test Team Leader
Kevin Hoffman	Braun Intertec	Inlet Sample Team Leader
David Hillesheim	Braun Intertec	Main Stack Sample Team Leader
Shawn Nelezen	Braun Intertec	Inlet Sample Technician
George Jansen	Braun Intertec	Main Stack Sample Technician
Ron McCloud	Phillips Analytical	Speciated Mercury Sample Analysis

EQUATIONS

Equation 1a - Dry Molecular Weight:

$$MWd = 0.440(\%CO_2) + 0.320(\%O_2) + 0.280(\%N_2 + \%CO)$$

Equation 1b - Wet Molecular Weight:

$$MWw = MWd\,(1\text{-}B\mathit{ws}) + 18.0(B\mathit{ws})$$

Equation 2a - Meter Volume at Standard Conditions:

$$Vm(std) = \frac{VmY(Tstd)(Pbar + \Delta H/13.6)}{(Tm)(Pstd)}$$

Equation 2b - Volume of Water Vapor Condensed:

$$Vwc(std) = K1(Wf\text{-}Wi)$$

Equation 2c - Moisture Content:

$$B\mathit{ws} = Vwc(std)/(Vwc(std) + Vm(std))$$

Equation 3a - Velocity at a Traverse Point:

$$Vd = KpCp(Ts\,\Delta P/PsMWw)^{1/2}$$

Equation 3b - Volumetric Flow Rate (Actual Basis):

$$Q = Vd(avg)Ad\ 60$$

Equation 3c - Volumetric Flow Rate (Standard Basis):

$$Qstd = Q\frac{(Tsd)(Ps)}{(Ts)(Pstd)}$$

Equation 3d - Volumetric Flow Rate (Standard Dry Basis):

$$Qstd(dry) = Qstd(1\text{-}B\mathit{ws})$$

Equation 4a - Isokinetic Sampling Nozzle Inside Diameter:

$$D_n = \left(\frac{(0.0358)QmPm}{TmCp(1 - Bws} \left(\frac{TsMWw}{Ps\Delta P} \right)^{1/2} \right)^{1/2}$$

Equation 4b - Isokinetic Sampling "X" Factor:

$$X = 846.72 \times Dn^4 \times \Delta H@i \times Cp^2 \times (1 - Bws)^2 \times \frac{(MWd \times Ps)}{(MWw \times Pm)}$$

Equation 4c - Orifice Pressure Drop at Isokinetic Sampling Rate:

$$\Delta H = X \times \Delta P \times \frac{(Tm)}{Ts}$$

Equation 4d - Sample Percentage of Isokinetic:

$$\%ISO = \frac{(TsavgVmstdPstd100)}{(TstdVdavg\theta\ A\ ns60(1 - Bws))}$$

Equation 4e - Concentration of Mercury Species (μg/dscm):

$$C = \frac{(Ms - Mb)}{(Vmstd \times 0.0283)}$$

Equation 4f - Mercury Species Emission Rate (gram/hr):

$$ER = \frac{(Ms - Mb)}{Vmstd} \times Qstd(dry) \times 60$$

Symbol Identification

An	=	Nozzle area (ft^2)
Ad	=	Area of duct (ft^2)
B*ws*	=	Water vapor in gas stream, proportional by volume
C	=	Mercury species concentration (μg /dscm)
Cp	=	Pitot tube calibration factor (unitless)
Dn	=	Inside diameter of sample nozzle (inches)
ER	=	Mercury species emission rate (gram/hr)
K1	=	Constant (0.04715 ft^3/g)
Kp	=	Constant (85.49)
Mb	=	Mass of mercury species in blank (μg - as defined in Section 15.1 of the Ontario-Hydro Method)
Ms	=	Mass of mercury species in sample (μg)
MWd	=	Duct gas dry molecular weight (lb/lb-mole)
MWw	=	Duct gas wet molecular weight (lb/lb-mole)
Pbar	=	Barometric pressure ("Hg)
Pm	=	Meter pressure (assumed to be 30"Hg)
Ps	=	Absolute stack pressure ("Hg)
Pstd	=	Standard pressure (29.92"Hg)
Q	=	Duct volumetric flow rate (actual cfm)
Qm	=	Assumed sampling rate (cfm)
Qstd	=	Duct volumetric flow rate (scfm)
Qstd(dry)	=	Duct volumetric flow rate (dscfm)
Tm	=	Absolute temperature at meter (^oR)
Ts	=	Absolute temperature of duct gas (^oR)
Tstd	=	Standard temperature (528^oR)
Vd	=	Duct velocity at a traverse point (ft/s)
Vm	=	Dry test meter volume (cf)
Vm(std)	=	Dry test meter volume at standard conditions (scf)
Vwc(std)	=	Volume of water vapor condensed at standard conditions (scf)
Wf	=	Final weight of impinger/absorber train (g)
Wi	=	Initial weight of impinger/absorber train (g)
X	=	Isokinetic orifice pressure drop sampling coefficient
Y	=	Dry test meter calibration factor (unitless)
%CO2	=	Duct gas carbon dioxide content (%volume)
%CO	=	Duct gas carbon monoxide content (%volume)
%ISO	=	Sample percentage of isokinetic (must be $100 \pm 10\%$)
%N2	=	Duct gas nitrogen content (%volume)
%O2	=	Duct gas oxygen content (%volume)
θ	=	Total sample time (minutes)
ΔH	=	Pressure drop across orifice ("H2O)
$\Delta H@i$	=	Orifice calibration coefficient ("H2O)
ΔP	=	Pressure drop across pitot tube ("H2O)

Coyote Station Mercury ICR

Coal Sampling Procedures

Composite coal samples were collected during each of the three flue gas sampling test runs. Samples were collected immediately upstream of two coal feeders, plant numbers 5 and 12. Each of the feeders is one of six feeders that are located on each side of Coyote's boiler. Sampling commenced 10 minutes prior to the start of each flue gas sampling run and continued at one-half hour intervals for the duration of the test. Each sub-sample was collected in a separate zip-lock bag and labeled with the date and collection time. Midway through each flue gas sampling run, the filter required replacing on the inlet sampling probe. The coal sub-sample that was collected immediately prior to probe filter replacement was not included in the composite coal sample for each respective test run. Consequently, four sub-samples were thoroughly mixed and riffled to produce two composite coal samples for each test run. One sample was set to the laboratory for analyses and the second was held at the plant for contingency purposes.

Ash Sampling Procedures

Plant personnel elected to include ash sampling as part of the mercury sampling and analyses program. Composite ash samples were collected from one row of baghouse hoppers that were oriented in the direction of flue gas flow. Samples were collected from System 2 Row A. Sub-samples were collected at one-half hour intervals beginning at the time of flue gas sample collection. The sub-samples from each test run were collected in a plastic lined container and then thoroughly mixed prior to collecting two composite samples from the container. One sample was set to the laboratory for analyses and the second was held at the plant for contingency purposes.

Name: Terry Graumann

Title: Mgr. Environmental Services

Date: September 30, 1999

Signature: